Vinson&Elkins

January 2014 Issue 21

V&E Climate Change Report

Special Issue: EPA's Proposed Greenhouse Gas NSPS

On September 20, 2013, EPA Administrator Gina McCarthy signed a proposal to establish new source performance standards ("NSPS") for greenhouse gas ("GHG") emissions from power plants. The publication of this proposal in the Federal Register on January 8, 2014, marks the start of the public comment period on EPA's proposal, which will close on March 10, 2014. This special issue of the Climate Change Report examines various elements of EPA's proposed rule.

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Introduction & Overview

How Did We get Here?

In 2007, EPA entered a consent decree with states and environmental groups obligating the Agency to promulgate GHG performance standards for both new and existing power plants.[1] EPA took its first public step in March 2012 when it proposed new source performance standards for electricity generating units ("EGUs") with a capacity greater than 73MW.[2] In this initial offering, EPA proposed to have a single, combined standard of 1,000 lbs CO_2/MWh for all new power plants regardless of their fuel source.[3] EPA took the unusual step of combining distinct sources—coal and natural gas-fired power plants—into a single category for regulation. EPA's proposal would have required all new coal-fired capacity to implement carbon capture and sequestration ("CCS") to meet the new standard.[4] Recognizing that CCS is not yet commercially available, EPA's 2012 proposal created a 30-year compliance option for new coal plants under which the plant could comply with a higher emissions standard for the first ten years of operation and then comply with a significantly lower standard to be achieved through future installation of CCS.[5] EPA received over 2.5 million comments on its 2012 proposal,[6] and missed its initial deadline of April 2013 to finalize the rule.

President Obama announced his Climate Action Plan in June 2013.[7] One of the major components of this plan is to reduce greenhouse gas emissions from the electricity generation sector.[8] Coincident with the announcement of the Climate Action Plan, President Obama issued a Presidential Memorandum directing EPA to re-propose the NSPS for power plants not later than September 20, 2013, and finalize the standards in a timely fashion.[9] In response to this Presidential request, the EPA Administrator signed a draft of the current proposal on the assigned date.

Subsequent to EPA's online release of the NSPS on September 20, 2013, Congressman Fred Upton and other members of the leadership of the House Energy and Commerce Committee sent a letter to Administrator McCarthy requesting the withdrawal of EPA's proposal.[10] The November 15, 2013 letter noted that the Energy Policy Act of 2005 prohibits EPA from setting NSPS standards under section 111 of the Clean Air Act in reliance on data from projects that have received funding under the Department of Energy's Clean Coal Power Initiative.[11] Because all three power plants upon which EPA relied in making its determination of best system of emission reduction ("BSER") for coal-fired plants received funding from this program, the Energy Policy Act prohibits their consideration in EPA's evaluation of "available" technologies. As a result, Chairman Upton's letter requested that EPA withdraw the NSPS proposal prior to publication in the Federal Register to "ensure that the agency does not propose standards beyond its legal authority."[12]

After a substantial delay, EPA published its proposed rule in the Federal Register on January 8, 2014.[13] The proposal maintains the same emission rates that were set forth in EPA's September 20th pre-publication version of the rule, including a standard for coal-fired units that will require the implementation of partial CCS.[14] The January 8, 2014 proposal contained no modifications to EPA's determination of BSER for coal-fired units.[15]

What is EPA Proposing?

In an important departure from the 2012 proposal, EPA is now proposing separate standards for coal and natural gas-fired power plants.[16] EPA's proposed standards will require that all new natural gas plants meet the GHG emission limit associated with the performance of natural gas combined cycle ("NGCC") technology, and that all new coal-fired plants meet the GHG

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1 *See* State of New York et al. v. EPA, No. 06-1322 (D.C. Circuit decree entered Sept. 24, 2007).

2 77 Fed. Reg. 22,392 (Apr. 13, 2012) (publishing rule signed by administrator Jackson on Mar. 27, 2012).

3 *Id.* at 22,394.

4 *Id.* at 22,406.

5 *Id.*

6 79 Fed. Reg. 1430 (Jan. 8, 2014).

7 Executive Office of the President, The President's Climate Action Plan (2013), *available at* http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

8 *Id.* at 6.

9 Presidential Memorandum, Power Sector Carbon Pollution Standards, June 25, 2013, *available at* http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

10 Letter from Fred Upton, Chairman, House of Representatives Committee on Energy and Commerce, to Gina McCarthy, Administrator, United States Environmental Protection Agency, Nov. 15, 2013, *available at* http://energycommerce.house.gov/sites/republicans.energycommerce.house.gov/files/letters/20131115EPA.pdf.

11 *Id.*

12 *Id.*

13 79 Fed. Reg. 1430.

14 *Cf. id.* at 1433, Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units at 15-16 (Pre-proposal version, Sept. 20, 2013) [hereinafter NSPS Pre-Proposal]

15 *Cf.* 79 Fed. Reg. at 1471-75, NSPS Pre-Proposal, *supra* note 14, at 215-37.

16 79 Fed. Reg. 1430.

emission limits that EPA associates with the performance of partial CCS.[17] EPA's proposal would not apply to modified or reconstructed sources.[18] EPA's regulatory impact analysis concludes that this proposal will have no impact on the electric power generation sector because, as a result of the abundance of cheap natural gas, no new coal-fired generation is projected to be constructed before 2030 and newly constructed natural gas plants already meet the proposed standard.[19] As discussed in more detail below, EPA's proposal may well guarantee the result it predicts as the financing of coal plants with partial CCS may prove infeasible.

EPA's proposal would apply to all new EGUs with a capacity greater than 250MMBtu/hr (73MW),[20] that supply more than 219,000MWh and more than one-third of their electric output to the grid on an annual basis.[21] If and when finalized, the NSPS will apply to covered facilities that commence construction after January 8, 2014, although the proposal specifically exempts certain facilities that have been issued permits but have not yet commenced construction.[22]

EPA is proposing two alternatives to codify these standards. In the first, changes would be made to existing subparts Da (covering steam generating units, including integrated gasification combined cycle ("IGCC") units) and KKKK (covering natural gas-fired stationary combustion turbines).[23] In the alternative, EPA proposes to retain its 2012 proposal and place all GHG standards for EGUs in a new subpart TTTT.[24]

Section 111(b) of the Clean Air Act ("CAA" or the "Act") requires EPA to determine the best system of emission reduction as the basis for the NSPS.[25] For new natural gas-fired units, EPA's proposal concludes that combined cycle ("NGCC") technology constitutes the BSER, and proposes two different emission standards based on the size of the turbine.[26] Stationary combustion turbines with design heat inputs greater than 250MW (850MMBtu/hr) must comply with a standard of 1,000 lbs CO_2/MWh, while smaller units—those with a capacity between 73MW (250mmBtu/hr) and 250MW (850mmBtu/hr)—must comply with an emission limitation of 1,100 lbs CO_2/MWh.[27] A source must demonstrate compliance with this standard on a 12-month rolling average basis.[28] The same standards apply to turbines configured in simple cycle that meet additional applicability requirements for amount of operation and sales to the grid, which are discussed in more detail below.

For new, coal-fired units, EPA is proposing standards for utility boilers and IGCC units that are based on a finding that partial implementation of CCS is the BSER. EPA's proposed emission standard for these sources is 1,100 lbs CO_2/MWh on a 12-month rolling average basis.[29] For coal-fired units, EPA is also proposing an alternative compliance option under which a source would have an emission limit of 1,050 lbs CO_2/MWh on an 84-month rolling average basis.[30] EPA's proposal states that the 84-month compliance obligation is intended to provide important operational flexibility and seeks comment on the appropriate emissions limitation in the range of 1,000 to 1,050 lbs CO_2/MWh.[31]

Deferral of Standards for Modified or Reconstructed Sources

Section 111 defines a "new source" as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source."[32] Under EPA's longstanding regulations implementing section 111 consistent with the statute, each new source performance standard applies to new, modified, and reconstructed sources.[33] Modification is further defined by statute to mean a physical alteration to or change in the method of operation of a facility that increases its

[17] *Id.*
[18] *Id.*
[19] EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units at 1-3 to 1-4 (Sept. 2013) [hereinafter NSPS RIA].
[20] 79 Fed. Reg. 1444.
[21] *Id.* at 1445-46.
[22] *Id.* at 1434.
[23] *Id.* at 1437.
[24] *Id.*
[25] 42 U.S.C. § 7411(b) (requiring EPA to promulgate standards of performance, defined in 42 U.S.C. § 7411(a)(1) to be "the degree of emission limitation achievable through the application of the best system of emission reduction.")
[26] 79 Fed. Reg. 1506; Table 2 to Subpart KKKK of Part 60, 79 Fed. Reg. 1510.
[27] *Id.* at 1510, Table 2 to Subpart KKKK of Part 60.
[28] *Id.* at 1506-07.
[29] *Id.* at 1502.
[30] *Id.* at 1502.
[31] *Id.* at 1448.
[32] 42 U.S.C. § 7411(a)(2).
[33] 40 C.F.R. §§ 60.1(a), 60.15(a).

emissions of an air pollutant,[34] while reconstruction is defined by regulation to mean replacement of components of an existing facility that exceed 50% of the cost of building a new facility.[35]

Notwithstanding the statute and the longstanding NSPS general provisions, EPA's present proposal explicitly applies only to new sources—which EPA defines as greenfield facilities and new EGUs added to existing facilities.[36] The preamble goes on to state "[w]hile this latter scenario can be considered the modification of existing sources under PSD, this proposed NSPS will not apply to modified or reconstructed sources as those terms are defined under [the NSPS implementing regulations in] part 60."[37] EPA also states that it has not done any analysis to evaluate whether the BSER determinations made in its current proposal would also be BSER for modified or reconstructed sources.[38] Curiously, EPA provides no legal justification for its decision to exclude modified or reconstructed sources in the current proposal.

The Presidential Memorandum, though not a source of legal authority, does set forth separate deadlines for the promulgation of NSPS for modified and reconstructed sources. The Presidential Memorandum calls upon EPA to develop standards for reconstructed and modified sources concurrent with performance standards under section 111(d) for existing sources. These standards are to be proposed no later than June 1, 2014, and finalized no later than June 1, 2015.[39]

EPA's Rational Basis Finding

Background

In 2007, the Supreme Court held that greenhouse gases fall within the definition of "air pollutants" at least for purposes of Title II of the CAA.[40] The Court held that, under section 202(a) of the CAA Act, EPA must determine whether greenhouse gas emissions from new motor vehicles cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare. As discussed in more detail below, EPA made such findings for mobile sources in its 2009 Endangerment Finding.

In the current proposal, EPA concludes that an additional endangerment finding is not a necessary precursor to its regulation of power plants under section 111 of CAA. Section 111(b) articulates the requirements for "standards of performance for new [stationary] sources" and requires that EPA create a list of categories of stationary sources that "cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health."[41] Power plants are currently listed as categories of stationary sources under this provision.

Once a source category is listed under section 111(b), EPA must "publish proposed regulations, establishing Federal standards of performance for new sources within such category."[42] A "standard of performance" is defined as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[43]

Section 111 does not expressly state a requirement that EPA make a pollutant-specific endangerment finding before subjecting new pollutants to regulation for a category already determined to "endanger" due to its emissions of another pollutant. EPA interprets the Act's silence as a requirement that it provide only a "rational basis" for the regulation of new stationary sources rather than a full-fledged endangerment finding.[44] EPA further asserts that it has met this burden based on its 2009 Endangerment Finding.

The 2009 Endangerment Finding

In 2009, following the Supreme Court's decision in *Massachusetts v. EPA*, EPA issued two distinct findings regarding GHG emissions under section 202(a) of the CAA.[45] The first was a finding that current and projected concentrations of six greenhouse gases (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) in the atmosphere threaten the health and public welfare of current and future generations (the "Endangerment Finding"). EPA relied upon assessments published by the U.S. Global Climate Research Program ("USGCRP"), the Intergovernmental Panel on Climate Change ("IPCC"), and the National Research Council ("NRC") as the primary scientific basis supporting the

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34 42 U.S.C. § 7411(a)(4).
35 40 C.F.R. § 60.15(b).
36 79 Fed. Reg. at 1489.
37 *Id.*
38 *Id.*
39 Presidential Memorandum, *supra* note 9.
40 *Massachusetts v. EPA*, 549 U.S. 497 (2007).
41 42 U.S.C. § 7411(b)(1)(A).
42 42 U.S.C. § 7411(b)(1)(B).
43 42 U.S.C. § 7411(a)(1).
44 79 Fed. Reg. 1453-54.
45 Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009).

Endangerment Finding. The second action, a "cause-or-contribute-significantly" finding, concluded that the combined emissions of GHGs from new motor vehicles and new motor engines contribute to the GHG pollution and threaten public health and welfare.

On its own, the Endangerment Finding did not create any new regulations or impose any new requirements for sources of GHGs. Rather, the Endangerment Finding was a necessary precursor to the regulation of GHG emissions from motor vehicles under Section 202 of the CAA. Based on these findings, EPA proceeded to implement restrictions on greenhouse gas emissions from light duty vehicles[46] and heavy-duty trucks.[47]

Several states and industry groups challenged the Endangerment Finding and other related rules in the D.C. Circuit. However, the D.C. Circuit upheld the rules, finding that they were neither arbitrary nor capricious and that the rules were adequately supported by the administrative record.[48] The plaintiffs appealed the D.C. Circuit's decision to the Supreme Court, and certiorari was denied on specific questions related to the adequacy of EPA's Endangerment Finding. The Court did, however, grant certiorari on the question of "[w]hether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases."[49] Because the Supreme Court's grant of certiorari did not extend to questions of the adequacy of the 2009 Endangerment Finding, the D.C. Circuit's decision upholding the Endangerment Finding for mobile sources will all but certainly stand.

EPA's "Rational Basis" Finding

In its proposed rule, EPA states that there is a statutory gap in the CAA regarding the requirements for the promulgation of a standard of performance under section 111. The Agency asserts that, based on the Supreme Court's holding in *Chevron U.S.A. v. NRDC*,[50] this statutory gap requires EPA to develop a reasonable interpretation of the statute. EPA therefore concluded that "in order to promulgate a section 111 standard of performance for a particular pollutant, [EPA does] not need to make a pollutant-specific endangerment finding, but instead must demonstrate a rational basis for controlling the emissions of the pollutant."[51] According to EPA, this rational basis can be demonstrated by relying on "information concerning the health and welfare impacts of the air pollution at issue, and the amount of contribution that the source category's emissions make to that air pollution."[52]

In support of its interpretation that only a "rational basis" is required, EPA points to the D.C. Circuit's opinion in *National Lime Ass'n v. EPA*,[53] in which the court upheld EPA's finding that particulate emissions from lime manufacturing plants contribute to air pollution. In that case, EPA based its finding on a prior determination that "the significant production of particulate emissions . . . cause[s] or contribute[s] to air pollution (which may reasonably be anticipated to endanger public health or welfare)" and that "the danger of particulate emissions' effect on health has been sufficiently supported in the Agency's [] previous determinations to provide a *rational basis* for the Administrator's finding in this case."[54] EPA also cites *National Asphalt Pavement Ass'n v. Train*,[55] in which the D.C. Circuit held that the Agency's establishment of NAAQs for particulate matter was sufficient to support the determination that particulate matter endangers the public health or welfare.[56]

EPA contends that it has a rational basis for concluding that CO_2 emissions from power plants contribute to adverse effects to public health and welfare based on its 2009 Endangerment Finding and the more recent scientific assessments and findings. EPA also asserts that, even if it is required to make a "cause-or-contribute-significantly" finding under section 111, because CO_2 is the "dominant anthropogenic greenhouse gas" and power plants "emit almost one-third of all U.S. GHG emissions," the same facts that support the Agency's rational basis determination would support such a finding.[57] However, EPA does not anywhere in the preamble or administrative record identify any reduction in ambient CO_2 levels or effects that it attributes to the rule it has adopted. To the contrary, EPA concludes that "this proposed rule will result in negligible CO_2 emission changes, quantified benefits, or costs by 2022."[58]

46 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards, 77 Fed. Reg. 62,624 (Oct. 15, 2012).

47 Heavy-Duty Engine and Vehicle, and Nonroad Technical Amendments, 78 Fed. Reg. 36,370 (June 17, 2013).

48 *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102 (D.C. Cir. 2012), *cert. granted*, *Chamber of Commerce of the United States v. EPA*, 134 S. Ct. 468 (Oct. 15, 2013)(No. 12-1272).

49 Lyle Denniston, *Court to Rule on Greenhouse Gases (UPDATE)*, SCOTUSblog (Oct. 15, 2013, 9:35 AM), http://www.scotusblog.com/2013/10/court-to-rule-on-greenhouse-gases/.

50 467 U.S. 837 (1984).

51 79 Fed Reg. at 1454.

52 *Id.*

53 627 F.2d 416 (D.C. Cir. 1980).

54 *Id*. at 431-32 n.48 (emphasis added).

55 539 F.2d 775 (D.C. Cir. 1976).

56 *Id.* at 784.

57 79 Fed. Reg. at 1455, 1456.

58 *Id.* at 1433.

The Coming Challenges

EPA's conclusion that only a "rational basis" finding is required is likely to be the subject of comments and potential future challenges to the proposed rule. For example, parties may argue that under section 111 of the CAA, EPA must make a new endangerment finding as a prerequisite for promulgating this rule. In the absence of any record showing the rules as adopted will accomplish any meaningful reductions in the dangers used to support their adoption, the basis for the rule's adoption is not so obviously "rational." Challengers will argue that in relying on the 2009 Endangerment Finding, EPA has taken an unacceptable short cut around the administrative process. They could contend that since the original Endangerment Finding was issued, the scientific understanding of GHG emissions and their impacts on the global climate have changed and must be reconsidered and analyzed in a new endangerment finding. While such an argument has legal merits, recent climate assessments with a veneer of quasi-governmental approval have expressed increased scientific certainty regarding both the impacts of global climate change and the role of GHG emissions.

Further, as mentioned above, EPA based the 2009 Endangerment Finding on the concentrations of six greenhouse gases. Challengers will likely argue that the statute requires EPA to make an endangerment finding on a pollutant-by-pollutant basis. In past litigation, parties have questioned whether EPA may regulate carbon dioxide independently in light of the combined treatment of the greenhouse gases in the Endangerment Finding.[59] It is reasonable to anticipate similar arguments in any challenges to EPA's new proposal.

Parties also are likely to challenge whether EPA's interpretation of the statute as requiring only a "rational basis" for the promulgation of regulations under section 111 is reasonable. Under the Supreme Court's holding in *Chevron*, if Congress has not spoken on a precise issue and Congressional intent is not clear, the Court will defer to the agency in its reasonable interpretation of the statute.[60] Challengers will first argue that Congressional intent is clearly discernible based on the text of the CAA and that section in particular when read as a whole and in context, leaving no "statutory gap" for EPA to fill. Second, they will contend that even if Congressional intent is not clear with respect to the requirements for issuing regulations under section 111, EPA's interpretation is far from reasonable and provides EPA with too much discretion in regulating stationary sources. Because no evidence in either the original Endangerment Finding or the record of the NSPS even attempts to establish that the selected regulations will do anything to mitigate the identified danger, the rules are subject to a very legitimate challenge to their rationality.[61] In fact, where useful to justify its choices, EPA claims that the rules do nothing at all to affect the future configuration of power generation or the emissions that will result.

Determination of the Best System of Emission Reduction

EPA's Authority to Determine Best System of Emission Reduction

Section 111(a)(1) of the CAA requires EPA, when promulgating an NSPS to set a standard of performance reflecting "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been *adequately demonstrated*."[62] EPA must balance four factors when the Agency determines BSER: technical feasibility,[63] the amount of emissions reductions,[64] technological development,[65] and costs.[66] The proposal avers that partial CCS represents BSER, but significant questions remain as to whether EPA's decision meets the requirements of the CAA.

EPA's proposal states the case law permits it to consider the factors above when determining BSER on a regional or national level over a period of time, and that the agency may consider additional factors on a plant-specific level at the time of its rulemaking.[67] The Agency notes that the D.C. Circuit has granted it "a great deal of discretion in weighing the various factors to determine the 'best system.'"[68] For example, in *Lignite Energy Council v. EPA,* the court upheld EPA's NSPS for nitrogen oxides emissions from utility and industrial boilers against industry challenges based on cost.[69] EPA determined that

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59 *Coalition for Responsible Regulation,* 684 F.3d 102 (D.C. Cir. 2012), *cert. granted*, *Chamber of Commerce of the United States v. EPA*, 134 S. Ct. 468 (Oct. 15, 2013)(No. 12-1272).

60 *Chevron*, 467 U.S. at 843.

61 This issue was proffered in at least one petition for certiorari challenging the tailpipe rules that followed EPA's initial endangerment finding, which the Supreme Court declined to hear. The NSPS rules may better present the question of whether EPA may lawfully enact rules in authorized to protect the public from danger without making any demonstration at all that the rules will meaningfully mitigate that danger.

62 42 U.S.C. § 7411(a) (emphasis added).

63 79 Fed. Reg. at 1468, 1471.

64 *Id.* at 1463 (citing *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981)).

65 *Id.* at 1465 (citing *Sierra Club*, 657 F.2d at 347).

66 *Id.* at 1464-65 (citing *Sierra Club*, 657 F.2d at 343; *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999)).

67 *Id.* at 1463 (citing *Sierra Club*, 657 F.2d at 330).

68 *Id*. (citing *Lignite Energy Council*, 198 F.3d at 933).

69 *Lignite Energy Council*, 198 F.3d 930.

selective catalytic reduction ("SCR") represented BSER for the boilers. Industry groups "argue[d] that SCR [was] not the "best demonstrated system" under section 111 because the incremental cost of reducing NO_x emissions would be considerably higher with SCR than with combustion controls" and that "[r]ecent improvements in combustion controls [would] enable many boilers to attain emissions levels close to EPA's SCR-based standards."[70] The court found that EPA relied on data showing that the new standards would only result in a modest cost increase in the production of electricity from new boilers, and that the incremental cost difference between SCR and combustion controls did not preclude EPA from determining that SCR represented BSER.[71] Thus, EPA did not exceed its discretion in selecting a more costly technology as BSER. However, although EPA enjoys considerable freedom in setting an NSPS,[72] courts will not sustain such decisions when the environmental or economic costs of implementing a technology are exorbitant.[73]

The D.C. Circuit has also observed that, "[a]lthough it is conceivable that a particular control technique could be considered both an emerging technology and an adequately demonstrated technology, there is inherent tension between the two concepts."[74] In *Sierra Club v. Costle*, the court examined EPA's consideration of dry scrubbers when setting the new NSPS for SO_2 emissions from coal-fired power plants based on a variable emissions standard.[75] In its examination of the record, the court noted that '"no full scale dry scrubbers are presently in operation at utility plants so information available . . . dealt with prototype units,"' and that "even testing on the pilot-scale has been limited."[76] Without an explanation of how the limited data could be extrapolated and applied to full-scale plants, the court decided that it was premature to find that dry scrubbers had been adequately demonstrated for the purposes of a BSER determination.[77] Thus, courts have expressed reservations that a technology has been adequately demonstrated when the available data is insufficient to predict performance in full-scale plants throughout the industry.

EPA Predicts Few Solid Fossil Fuel-Fired EGUs will be built before 2020.

The Agency predicts that few, if any, coal-fired power plants will be built without CCS technology before 2020.[78] Because no plants will need to satisfy EPA's NSPS requirements during that time period, EPA believes that its proposed rule will impose no significant costs on the industry. Instead, EPA believes that plants would likely implement technologies that meet its standards even if it did not issue this proposal.[79] To reach this conclusion, EPA relied on both its own modeling and modeling by the Energy Information Administration ("EIA").[80] EPA's modeling projects that natural gas prices will continue to be less than coal prices, and that the installation of CCS does not effect this conclusion.[81] More specifically, EPA calculates that new coal construction could compete with a natural gas price of $10 per MMBtu (also including carbon risk) without a market for the captured CO_2.[82] However, the average delivered natural gas price to the power sector in 2012 was $3.44 per MMBtu.[83] These models forecast that new unplanned coal capacity will only be built when there is a market for the captured CO_2, and therefore only plants with integrated carbon capture will be economically viable within EPA's 2020 time horizon.

As noted above, EPA's proposal may guarantee the result it predicts if the financing of coal plants with partial CCS proves infeasible. As explained in greater detail below, recent CCS projects have faced significant construction delays and cost overruns. State utility commissions have shown reluctance to allow utility projects using partial CCS to attempt to recover increased project costs through the ratemaking process. Although the Department of Energy ("DOE") still has ample funding to support CCS-related projects, past difficulties with DOE's FutureGen project have raised concerns about the success of government-backed projects.[84] Conceived in 2003, FutureGen would have been a 10-year project to build a coal-fired power

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70 *Id.* at 933.

71 *Id.*

72 *See* New York v. Reilly, 969 F.2d 1147, 1150 (D.C. Cir. 1992).

73 *Lignite Energy Council*, 198 F.3d at 933.

74 *Sierra Club*, 657 F.2d at 341 n.157.

75 The Sierra Club and other parties challenged EPA's decisions to set the NSPS based on a variable control option, Under this optional standard, a coal-fired power plant could reduce its SO_2 emissions by less than 90 percent of potential uncontrolled emissions if the amount of SO_2 emitted following the use of pollution control technology was less than 0.60 lb/MBtu. *Id.* at 312. The standard did not allow plants to reduce emissions by less than 70 percent of potential uncontrolled emissions. *Id.* at 350. "As a result of this option, the NSPS requirements for percentage reduction of [SO_2] removal var[ied] on a sliding scale ranging from a minimum of 70 percent to a maximum of 90 percent." *Id.* at 316. The 70 percent floor imposed by the NSPS effectively required coal-fired plants "to employ some form of flue gas desulfurization ("FGD" or "scrubbing") technology." *Id.* The variable standard rested on the premise that industry would use wet, as opposed to dry, scrubbing technology to comply. *Id.* at 341.

76 *Id.* at n.157.

77 *Id.* at 341.

78 NSPS RIA, *supra* note 19, at 5-1.

79 79 Fed. Reg. 1433, 1495

80 *Id.* at 1433.

81 NSPS RIA, *supra* note 19, at 5-23 – 5-24.

82 *Id*. at 5-24 – 5-25.

83 *Id*. at 5-13.

84 Peter Folger, Cong. Research Serv., R42496, Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy 1 (2013).

plant integrating partial CCS and would have produced 275 megawatts of electricity.[85] The project eventually failed, although DOE plans to retrofit an existing coal-fired power plant in Illinois with CCS as part of its FutureGen 2.0 project.[86] Uncertainty surrounding the success of coal plants with partial CCS will likely result in difficulties obtaining private financing, which will further reduce the likelihood of project developers pursuing coal plants.

The Alternative Strategies that EPA Considered

EPA evaluated three alternatives when it chose a control strategy to satisfy the BSER standard: (1) technology that does not include CCS; (2) technology with "full capture" (above 90%) CCS; and (3) technology with "partial capture" CCS.

Non-CCS Alternative

EPA considered three alternative technologies that did not include any carbon capture and instead focused only on efficiency: supercritical pulverized coal ("SCPC"), a circulating fluidized bed ("CFB") boiler, and a modern IGCC unit. EPA decided that these alternatives were not the BSER because they produced significantly higher emissions levels than those achieved by the CCS option.[87] EPA also concluded that an option excluding CCS could not be the best system of emission reduction because it would not advance the development of technologies to reduce CO_2 emissions from existing EGUs. EPA cited American Electric Power Co.'s ("AEP") cancellation of a large-scale CCS retrofit demonstration project on one of their coal-fired power plants for support that a non-CCS alternative would actually create disincentives to the development of CCS.[88] State utility regulators would not approve cost recovery for CCS investments without a regulatory requirement to reduce CO_2 emissions, which led to AEP cancelling the project in 2011.[89] Considering these factors, EPA determined that some degree of CCS represented the appropriate BSER.

There is some support in the legislative history and case law for EPA's authority to use BSER as a technology-forcing measure. For example, the Senate committee that voted on section 111 observed that section 111 was designed to encourage "constant improvement in techniques for preventing and controlling emissions from stationary sources,"[90] and an emergent technology could serve as a standard of performance even if it were not "in actual routine use somewhere."[91] The D.C. Circuit has also interpreted the phrase "adequately demonstrated" in Section 111 as "look[ing] toward what may fairly be projected for the regulated future, rather than the state of the art at present."[92] However, EPA must have "test data . . . representative of potential industry-wide performance" before establishing the CO_2 emissions level achievable by any add-on control technology."[93] The three DOE-sponsored projects and the Canadian government-backed CCS project are not yet operational and arguably do not provide substantial evidence that CCS has been adequately demonstrated. Furthermore, when Congress passed the Energy Policy Act of 2005, it specifically precluded EPA from using DOE funded projects like the ones cited in the rule as a basis for determining that a technology had been "adequately demonstrated" as required by section 111.[94]

Partial Compared to Full CCS

EPA selected partial CCS instead of full CCS based on BSER's cost criterion and the systems implemented in coal-fired plants that are currently under development. The Agency noted that nearly all of these new plants are designed to use either a partial CCS system or a full CCS system (usually 90% or greater capture) and most intend to sell or use the captured CO_2 to generate additional revenue.[95] EPA also observed that some companies are considering a range of options, including nuclear, biomass, and geothermal units, both as an alternative to gas (promoting fuel diversity) and as a means to generate base-load

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85 *Id.* at 1 n.3.
86 *Id.* at 1.
87 79 Fed. Reg. at 1468-69
88 *Id.* at 1469
89 *Id.*
90 S. Rep. No. 91-1196, at 17 (1970).
91 *Id. at* 16.
92 *Lignite Energy Council,* 198 F.3d at 934 (quoting *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973)); *see also* Sierra Club, 657 F.2d at 364 (stating that the court "believe[s] EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.").
93 *See* Sierra Club, 657 F.2d at 377.
94 *See* 42 U.S.C. 15962(i) ("No technology, or level of emission reduction solely by reason of the use of technology, or the achievement of the emission reduction by 1 or more facilities receiving assistance under this Act, shall be considered to be (1) adequately demonstrated for purposes of [section 111 of the Clean Air Act] . . ."); 26 U.S.C. 48A(g) ("No use of technology . . . at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology is (1) adequately demonstrated for purposes of section 111 of the Clean Air Act"); see also H. Comm. on Energy and Commerce, Report on H.R. 1640, "Energy Policy Act of 2005," H.R. Rep. No. 109-215, at 239-40 (July 29, 2005) (July 29, 2005)("the use of a certain technology by any facility assisted under this subtitle . . . will not result in that technology . . . being considered achievable, achievable in practice, or 'adequately demonstrated' for purposes of [section 111 of the Clean Air Act])."
95 79 Fed. Reg. at 1435. Southern Company's Kemper Facility "will include a CCS system designed to capture approximately 65 percent of the produced CO_2," SaskPower's Boundary Dam Project, the Texas Clean Energy Project, and the Hydrogen Energy California plant anticipate 90 percent capture. *Id*.

power with a lower carbon footprint.[96] These alternatives are less costly than full capture CCS, but are comparable to new coal units that implement partial CCS. Because the cost of "full capture" CCS without EOR is outside the range of costs that companies are considering for comparable generation, EPA concluded that full capture should not be considered BSER for CO_2 emissions for coal-fired power plants.[97]

By contrast, partial capture offers enhanced "operational flexibilities" by allowing operators to adjust carbon capture rates during peak versus non-peak electricity demand periods. This feature "optimize[s] the operation and minimize[s] the cost of CCS in new fossil fuel-fired projects."[98] Furthermore, unlike full CCS, EPA found that partial CCS will allow project developers to continue to use conventional syngas combustion turbines instead of advanced hydrogen turbines.[99] EPA also predicts that partial CCS will reduce the need for multi-stage water-gas shift reactors. Altogether, EPA estimates that the difference in cost per MWh is $92/$97 (SCPC/IGCC) for partial CCS versus $147/$136 (SCPC/IGCC) for full CCS.[100] According to a Department of Energy/National Energy Technology Laboratory study, partial CCS can reduce CO_2 emissions by 25 to 75 percent, which corresponds to emissions of approximately 1,060 to 380 lbs CO_2/MWh-gross.[101] EPA's proposed standard of performance—1,100 lbs CO_2/MWh-gross—rests at the high end of this range.[102]

Has EPA "Adequately Demonstrated" that CCS is Technically Feasible and Available?

Domestic CCS projects have yet to achieve large-scale results, raising questions regarding whether or not CCS meets the CAA's requirements for BSER. One Congressional Research Service report notes that, to date, "there are no commercial ventures in the United States that capture, transport, and inject large quantities of CO_2 . . . solely for the purposes of carbon sequestration."[103] In its proposal, EPA points to Southern Company's Kemper County Project as proof that partial CCS has been adequately demonstrated.[104] The project is a coal-fired power plant that incorporates CCS and is expected to begin operation sometime in 2014. However, construction costs "have raised questions over the relative value of environmental benefits due to CCS technology compared to construction costs of the facility and its effect on ratepayers."[105] Without at least one successful full-scale project to support its conclusions, EPA may find its BSER determination susceptible to challenge on grounds that it does not meet the requirements outlined in the D.C. Circuit's review of past NSPS BSER determinations and because of the prohibition contained in Energy Policy Act of 2005 noted above.[106]

The proposed rule cites several examples of upcoming projects that incorporate partial CCS for support that the technology has been adequately demonstrated. EPA specifically pointed to four IGCC projects as evidence that CCS represents BSER: (1) Southern Company's Kemper County Energy Facility; (2) SaskPower's Boundary Dam CCS Project in Estevan; Saskatchewan; (3) Summit Power's Texas Clean Energy Project; and (4) the Hydrogen Energy California Project.[107] EPA also noted that NRG is developing a commercial-scale post-combustion carbon capture project at its W.A. Parish generating station southwest of Houston, Texas. EPA acknowledges that all of the demonstration projects cited in the proposed NSPS have required substantial taxpayer support and rely on co-production of steam or other products to make the projects commercially viable.[108] However, the Agency notes that the utility industry has traditionally received some form of government subsidy, ranging from indemnification protections for nuclear power to tax breaks for renewable energy.[109] Importantly, EPA's proposal does not directly respond to Congressman Upton's letter or the limitations on consideration of government-subsidized projects under the Energy Policy Act of 2005.

Southern Company reacted to EPA's proposal by cautioning that its Kemper project "cannot be consistently replicated on a national level" and therefore "should not serve as a primary basis for new emissions standards."[110] The Kemper project faces multiple cost and construction issues, which raise questions as to whether it can serve as a proper example that CCS has been "adequately demonstrated." The plant originally expected to complete construction and begin operation by the end of 2013, but Southern has twice delayed the plant's start up, first to May 2014, then to "later in 2014." In July, Southern

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96 *Id*. at 1477.
97 *Id*.
98 *Id.* at 1470.
99 *Id*.
100 *Id*. at 1435.
101 *Id*. at 1470.
102 *Id*.
103 Peter Folger, Cong. Research Serv., R42496, Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy 22 (2013).
104 79 Fed. Reg. at 1478.
105 Peter Folger, Cong. Research Serv., R42496, Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy Summary 1 (2013).
106 *Sierra Club*, 657 F.2d at 378.
107 79 Fed. Reg. 1474-75.
108 *Id.* at 1478.
109 *Id.* at 1479.
110 Rebecca Smith and Cameron McWhirter, '*Clean Coal' Costs on Display at Mississippi Plant*, WALL STREET JOURNAL ONLINE, Oct. 13, 2013, http://stream.wsj.com/story/latest-headlines/SS-2-63399/SS-2-353439/.

boosted Kemper's cost estimate to $3.87 billion, exclusive of federal grants, the costs of the coal mine, CO_2 pipeline system, and other items.[111] These announcements prompted the Mississippi Power Commission to investigate whether the company has spent money prudently on the power plant as required by state law.[112] Also, the Sierra Club, which withdrew its original support for the plant, has asked the Commission to reject any further spending increases requested by the company and prevent the company from recovering additional project costs from consumers. Because the Kemper project represents the first large-scale CCS project, the fate of this facility will likely shape the ongoing debate over partial CCS' feasibility and availability.

Applicability Issues

Net v. Gross Output

EPA's proposal includes performance standards that limit the pounds of CO_2 that a facility may emit per megawatt-hour.[113] In order to ensure that the emissions standards are based upon the output of "useful recovered energy," EPA has proposed to base these standards on a facility's "adjusted gross output."[114]

Subpart Da—the provisions regulating utility boilers—currently uses "adjusted gross output" when calculating performance standards for criteria pollutants. Under that Subpart, "adjusted gross output" is defined as the "gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors . . . plus 75 percent of the useful thermal output . . . ."[115] After subtracting the electricity used to power feedwater pumps and associated gas compressors from the calculation of these performance standards, integrated gasification combined cycle facilities emit criteria pollutants at approximately the same rate as a comparable coal-fired unit when complying with applicable performance standards.[116]

EPA's 2012 proposal, which proposed a single, combined standard of 1,000 lbs CO_2/MWh for all new power plants regardless of their fuel source, omitted the subtraction of electricity used to power feedwater pumps and associated gas compressors in its proposed definition of gross output.[117] EPA reasoned that this was appropriate because this equipment was irrelevant to the gross efficiency of the best system of emission reduction—natural gas combined cycle systems—under the combined approach set forth in that proposal.[118] However, EPA requested comment on the use of net output-based standards, as it believed that the gross output definition might incentivize the use of less efficient equipment.

EPA's current proposal splits the difference between the current Subpart Da approach and that proposed in 2012. Specifically, EPA has proposed to subtract the electricity used to power feedwater pumps when calculating "gross energy output" under the proposed rule, but not subtract the electricity used to power associated gas compressors due to difficulties in implementing this measurement at co-production facilities.[119]

However, EPA has once again requested comment on the use of net output, either as an alternative compliance option or in place of gross output, in the performance standard calculation. Under EPA's current proposal, a net output-based standard would define net output as a unit's "gross electrical output . . . minus the parasitic (i.e., auxiliary) power requirements."[120] The parasitic load would include "any of the loads or devices powered by electricity, steam, hot water, or directly by the gross output of the . . . unit that does not contribute electrical, mechanical, or thermal output."[121]

EPA's request for comment is important because the use of a net output-based standard, either as a compliance alternative or in lieu of an adjusted gross output standard, could provide important flexibility for coal-fired power plants; while a natural gas combined cycle plant would see relatively smaller benefits from use of a net output-based standard, a coal-fired power plant could be allowed to emit as much as an additional 200 lbs CO_2/MWh when using a net output-based standard,

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[111] Scott DiSavino, *Southern Boosts Costs, Delays Mississippi Kemper Coal Plant Start,* REUTERS, Oct. 30, 2013, http://www.reuters.com/article/2013/10/30/utilities-southern-kemper-idUSL1N0IK10L20131030.

[112] *PSC Asking for More Information on Kemper Coal Plant,* ASSOCIATED PRESS, Oct. 16, 2013, http://msbusiness.com/blog/2013/10/16/psc-asking-information-kemper-coal-plant/.

[113] *See* 79 Fed. Reg. at 1503 (amending 40 C.F.R. § 60.46Da(c)); *see also id.* at 1510 (adding 40 C.F.R. § 60.4326; Subpart KKKK Table 2).

[114] *Id.* at 1446-48.

[115] 40 C.F.R. § 60.41Da.

[116] 79 Fed. Reg. at 1447. Absent these adjustments, an integrated gasification combined cycle facility complying with the criteria pollutant standards would emit higher levels than a comparable complying coal fired unit. *Id.*

[117] *Id*.

[118] *Id.*

[119] *Id.*

[120] *Id*.

[121] *Id.*

depending on the applicable emission limitation and the parasitic load at a particular plant.[122] Moreover, a net output-based approach would incentivize the use of more efficient designs, fuels, and equipment at all plants.[123]

Simple Cycle Turbines

Under the 2012 proposed performance standards, EPA proposed to exclude simple cycle turbines from having to comply with the rule because they operate too infrequently and contribute only small amounts of GHGs when compared to combined cycle turbines.[124] Some commenters opposed the exclusion, suggesting it created an incentive for operators to shift some loads from regulated combined cycle sources to unregulated simple cycle sources.[125] In response, EPA's current proposal would close this supposed loophole by making the new 1,000 to 1,100 lbs CO_2/MWh performance standards apply to both simple and combined cycle sources equally as long as they meet two power generation thresholds: (1) they sell more than one-third of their potential electric output and (2) they generate more than 219,000 MWh net electric output to the grid per year

Natural gas-fired EGUs generally use either simple cycle or combined cycle combustion turbines. Depending on load and usage, combined cycle turbines can be more efficient at full load than turbines without heat recovery steam generation. These units operate most efficiently when they are run continuously. Simple cycle turbines, though potentially slightly less efficient if run at full load, are designed to be quickly ramped up and down in order to meet demand during peak operating periods, so can be more efficient under certain dispatch scenarios. They are also less expensive to build and maintain. Economics determine which turbines operate to meet electrical demand. Quick ramping ability is important to supporting intermittent renewables, too, such as solar and wind.

Under EPA's current proposal, whether the performance standards apply depends on electricity sales alone. The proposed performance standards would apply if the facility supplies more than one-third of its potential electric output, as measured on a rolling three-year basis, and more than 219,000 MWh net electric output to the grid, as measured annually.[126] EPA is requesting comment on whether the one-third capacity factor should be as low as 20 percent or as high as 40 percent.[127] According to EPA, simple cycle turbines offer the lowest cost of electricity when operating below approximately 20 percent capacity, and conventional combined cycle facilities offer the lowest cost of electricity when operating between 20 and 40 percent capacity.[128] Setting the capacity factor for exclusion from the performance standards at 40 percent, and not 33 percent, would allow conventional combined facilities built with the intent to operate at relatively low capacity factors to serve as an alternative to simple cycle facilities because neither would be subject to the new performance standards.[129]

EPA is also seeking comment on what time period to use to measure applicability with the one-third sales criterion. EPA proposes to measure a facility's electric output on a rolling three-year basis, and not annually, in order to allow simple cycle turbines to operate at a high capacity during individual years with abnormally high electric demand without triggering the performance standards.[130] According to EPA, only 0.2 percent of existing simple cycle turbines exceeded this threshold on a rolling three-year basis. EPA is considering whether to instead measure a stationary combustion turbine's electric output on an annual basis, and EPA suggests raising the one-third electric sales criterion to two-fifths (40 percent).[131] During the period between 2000 and 2012, only 0.4 percent of existing simple cycle turbines exceeded this threshold on an annual basis.

Other Applicability Considerations

Another important change in EPA's current proposal is that facilities that primarily burn non-fossil fuels but co-fire a fossil fuel (e.g., a biomass facility) would not be subject to the rules as long as the fossil fuel component is not more than 10 percent of the heat input on a three-year rolling average basis.[132] EPA's previous proposal would have applied to biomass facilities that co-fire a fossil fuel, regardless of the percentage of the fossil fuel component.[133] Any perceived "carbon neutrality" for biogenic feedstock is not the reason these stationary sources are excluded from EPA's new proposed rules. Rather, EPA notes that its review of a Science Advisory Board advisory on EPA's proposed accounting approach for biogenic feedstock is ongoing, and EPA plans to move forward as warranted once that review is complete.[134] In accordance with Intergovernmental Panel on Climate Change guidance, however, GHG emissions from combustion of biogenic feedstock is accounted for in the forestry or agricultural sectors, not the energy sector.

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122 *Id.* at 1448, Table 4 – Subpart D_A Emission Rates.
123 *Id.* at 1447-48.
124 77 Fed. Reg. at 22,398.
125 79 Fed. Reg. at 1459.
126 *Id.*
127 *Id.*
128 *Id.*
129 *Id.*
130 *Id.*
131 *Id.*
132 *Id.* at 1446.
133 State Implementation Plans: Response to Petition for Rulemaking; Finding of Excess Emissions During Periods of Startup, Shutdown, and Malfunction; Proposed Rule, 77 Fed. Reg. at 22,399.
134 79 Fed. Reg. at 1446.

SSM Requirements

EPA proposes uniform emission standards at all times, including during startup and shutdown periods for CO_2 emissions for new fossil fuel-fired electric generating units.[135] This provision of the proposed rule is consistent with EPA's SSM policy, which calls for emission limitations applicable during all startup and shutdown events. To account for SSM events in setting the proposed output-based CO_2 standard, EPA is incorporating startup and shutdown periods as periods of partial load operation. In calculating compliance with the standard, the method proposed by EPA is to sum the emissions for all operating hours and to divide that by the sum of the electrical energy output and useful thermal energy output over a rolling 12-operating-month period.[136] In essence, the calculation will provide the average annual emissions of the source while it is in operation. EPA expects the impact of the periods of startup and shutdown on the total average to be minimal based on the assumption that the duration and power generated during these periods will be small relative to total operating time and power generation.

In addition, consistent with D.C. Circuit decisions and EPA's recent SIP call, the Agency has determined in the proposed rule that section 111 does not require that emissions occurring during periods of "sudden, infrequent, and not reasonably preventable" malfunctions be factored into the development of the standards.[137] Section 111 states that the Agency set a standard of performance which reflects the degree of emission limitation achievable through the application of the best system of emission reduction that is adequately demonstrated, as determined by EPA.[138] However, EPA's proposal states that the "application of the best system of emission reduction" should involve a source operating a unit in such a way as to avoid malfunctions and applying this concept during a malfunction period would provide difficulties.[139] In particular, accounting for malfunctions might lead to less stringent standards compared to the levels achieved by a well-performing, non-malfunctioning source.[140] The proposal also states that incorporating malfunctions into emissions calculations would be impracticable given the myriad types of malfunctions that can occur, and given the difficulty of estimating the frequency, degree, and duration of these malfunctions.[141] EPA asserts that its "approach to malfunctions is consistent with section 111 and is a reasonable interpretation of the statute."[142]

One issue that may arise is whether it is feasible to apply this method of calculating emissions to simple cycle combustion turbines ("SCCT") used for "peaking" (i.e. a few hours per day). For these, the total time of startup and shutdown periods compared to the overall operation time may skew the average annual emissions. However, in the proposed rule, EPA differentiates between EGUs and non-EGUs. EGUs are classified as sources used primarily for generating electricity for sale to the grid. EPA stated that most SCCTs, which typically sell less than one-third of their potential electric output to the grid, will not be classified as EGUs, and therefore do not fall within the purview of the proposal.[143]

Another issue is whether existing Title V permits would require updating to be consistent with the changes made in the proposal. Most Title V major source permits contain several SSM event provisions. Updating state rules and permits could require extensive time and manpower to align state standards and permit emission limits with EPA's SSM policy and criteria. In addition, EPA and state agencies may face problems when attempting to distinguish excess emissions caused by a malfunction as opposed to those caused by a startup or shutdown event. It is not clear from the proposal how facilities and permitting authorities should make this determination.

Using Enhanced Oil Recovery for Compliance

Enhanced oil recovery ("EOR") represents a potential option for the beneficial use of captured CO_2 emissions. EPA's proposal incorporates existing Underground Injection Control Program ("UIC Program") rules[144] and the Mandatory Reporting for Greenhouse Gases Rule ("Mandatory Reporting Rule")[145] to establish reporting and verification requirements for coal-fired plants implementing CCS.[146] The UIC Program regulates the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. Established under the authority of the Safe Drinking Water Act, these rules were designed to protect underground sources of drinking water. The regulations group injection wells into six "classes" of wells. EPA's proposal involves two of the six classes: Class II wells and Class VI wells. Class II wells include salt water disposal wells, hydrocarbon storage wells, and EOR wells. Class VI wells are used for injecting CO_2 into underground

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135 79 Fed. Reg. at 1448.
136 *Id.* at 1449.
137 *Id.*
138 42 U.S.C. § 7411(a)(1).
139 79 Fed. Reg. at 1449.
140 *Id.*
141 *Id.*
142 *Id.*
143 *Id.* at 1434.
144 40 C.F.R. pt. 144.
145 40 C.F.R. pt. 98.
146 *See* 79 Fed. Reg. 1482.

subsurface rock formations for long-term storage, or geologic sequestration (part of the CCS process).[147] Geologic sequestration involves different technical issues and much larger volumes of CO_2 than that used in EOR.

The proposed rule would require any facility that captures and injects enough CO_2 to meet the 1,100 lbs CO_2/MWh standard, onsite or off-site, to report under 40 C.F.R. Part 98 Subpart RR.[148] For off-site injection, EPA proposes to limit the facilities to which coal-fired plants may send captured CO_2 to UIC Class VI facilities and Class II facilities opting in to Subpart RR.[149] This requires Class II facility owners or operators that wish to continue receiving CO_2 captured by coal-fired plants to opt in under Subpart RR and undertake extensive monitoring and reporting under an EPA-approved plan.

Both Class II and Class VI rules govern siting, well construction, operating, monitoring, testing, reporting, financial responsibility, and closure requirements to protect underground sources of drinking water. Unlike the Class II requirements, however, Class VI rules contain extensive monitoring requirements, including the development of a comprehensive testing and monitoring plan that measures the mechanical integrity of the well, groundwater, and the location of injected CO_2 and the associated area of elevated pressure.[150] And post-injection monitoring must continue until all risks to underground sources of drinking water disappear.

EPA's proposal also integrates the Mandatory Reporting Rule, which requires large sources and suppliers in the United States to report GHG data on an annual basis. The rule applies to three sources: (1) sources that generate electricity;[151] (2) sources that supply CO_2 to the economy;[152] and (3) sources that inject CO_2 underground for geologic sequestration.[153]

Subpart D requires owners or operators of facilities that contain EGUs to report CO_2 emissions from EGUs and all other source categories located at the facility for which methods are defined in Part 98. They are required to collect emission data, calculate GHG emissions, and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting. Coal-fired plants must report CO_2 emissions from EGUs under this Subpart.

Under Subpart PP, CO_2 suppliers that meet the applicability requirements of Part 98 must report CO_2 emissions that would result from the complete release of the product they place into commerce. "Suppliers" consist of: (1) facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream to sequester or otherwise inject it underground; (2) facilities with CO_2 production wells; (3) importers of bulk CO_2 in excess of 25,000 tons of CO_2 equivalent ("CO_2e") per year; and (4) exporters of bulk CO_2 in excess of 25,000 tons CO_2e per year. These suppliers must report the mass of CO_2 captured from production process units and extracted from production wells, and the mass of CO_2 that is imported and exported. Coal-fired plants that capture CO_2 are required to report quantities of CO_2 captured and injected onsite or transferred off-site under this Subpart.

Subpart RR applies to facilities, such as a well or group of wells, that conduct geologic sequestration. Owners or operators of these wells must report the amount of CO_2 received for injection, develop and implement an EPA-approved monitoring, reporting, and verification plan, and report the amount of CO_2 sequestered using a mass balance approach and perform annual monitoring activities. This source category includes all UIC Class VI wells. Wells that conduct EOR are not subject to this rule unless the owner or operator opts-in to the Subpart RR source category.

In sum, if a coal-fired plant sends captured CO_2 off-site, it may send the CO_2 only to Class VI facilities or Class II facilities opting in under Subpart RR. To ensure compliance, EPA would modify 40 C.F.R. part 98 subpart PP to include: (1) the electronic GHG Reporting Tool identification ("e-GGRT ID") for the facility from which CO_2 was captured, and (2) the e-GGRT ID for, and mass of CO_2 transferred to, each geologic sequestration site (or ER well) reporting under Subpart RR.

Allowing coal-fired plants to send CO_2 to Class II wells that opt-in to Subpart RR raises questions about potential requirements under the Resource Conservation and Recovery Act ("RCRA"). On January 3, 2014, EPA finalized a conditional exclusion for CO_2 injected in UIC Class VI wells as part of EOR activities.[154] EPA's conditional exclusion did not extend to Class II wells that inject CO_2 for EOR, but the preamble noted that EPA expects that the use of CO_2 for EOR "would not generally be a waste management activity."[155] However, were EOR operators to determine that CO_2 streams are a RCRA characteristic waste in the future, the requirements of RCRA would apply to the management, transportation, and disposal of CO_2 used in EOR activities.

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147 40 C.F.R. § 144.6(f).
148 79 Fed. Reg. at 1483, 1514.
149 *Id.*
150 40 C.F.R. pt. 146 subpt. H.
151 40 C.F.R. pt. 98 subpt. D.
152 *Id.* at subpt. PP.
153 *Id.* at subpt. RR.
154 79 Fed. Reg. 350 (Jan. 3, 2014).
155 *Id.* at 355.

Interstate Jurisdictional Issues Associated with CCS

EPA's proposal raises several enforceability and transboundary issues with respect to EOR and CCS. CCS and EOR activities in one state involving CO_2 generated from sources in another state raise complicated statutory and constitutional questions about how far one state can reach across its own borders to ensure compliance with the NSPS. EPA's proposal raises the question of how a state can enforce a limit on a source that has shipped its captured CO_2 emissions outside that state's boundaries. Currently, almost all states have been delegated or are in the process of receiving GHG PSD permitting authority. EPA's proposal suggests that states issuing a PSD permit for sources subject to the NSPS include a condition within the permit that the captured CO_2 that the permittee sends offsite from the facility is transferred to an entity that is subject to the requirements of Subpart RR of the Mandatory Reporting Rule.[156] EPA assumes, but does not include any method to guarantee, that the receiving entity will inject the CO_2, thereby allowing the emitting source to comply with the terms of its permit.

If the receiving entity does not inject the CO_2, it is not clear that the permitting state has any authority to take action against that entity because a state cannot regulate activities occurring outside of its own borders. Similarly, it is not clear what action the permitting authority could take against the emitting source within its own state. EPA's proposal would only require an emitting source to send its CO_2 emissions to a facility covered under the proposed Subpart RR. Once the emitter meets this requirement, that facility would have complied with the terms of its permit. An enforcement gap could exist if a permitting authority is confronted with a situation where the only party subject to its authority has not violated any environmental laws, but actual control of the regulated pollutants has not occurred. Additionally, the proposed Subpart RR is only a reporting rule. It does not require actual injection of CO_2. The cancelled Indiana Gasification facility highlights this issue. As proposed, the Indiana Gasification project would have involved a synthetic natural gas facility in Indiana capturing its CO_2 emissions and transporting liquefied CO_2 via pipeline to the Gulf Coast for use in EOR.[157] The Indiana Department of Environmental Management ("IDEM") issued a draft permit for the facility, but commenters noted that nothing in the permit actually required injection of CO_2 into the ground once it reached the EOR sites.[158] The commenters argued that the terms of the permit did not meet the requirements of the CAA because there was no way to demonstrate that captured CO_2 emissions would not ultimately be released into the air after entering the pipeline.[159] In the final permit, IDEM responded that EPA's Environmental Appeals Board has held that, "BACT is a 'site-specific determination and . . . the combined results of the considerations that form the BACT analysis are the selection of an emission limitation and a control technology that are *specific to a particular facility*.'"[160] Therefore, IDEM did not need to consider emissions downstream of the facility after CO_2 had been captured and routed to the pipeline.

EPA's new proposal does nothing to address the concerns raised by Indiana Gasification's draft permit, nor does it address the potential enforcement concerns discussed above. Imposing a limit on one end of the pipeline without imposing a limit on the other will not guarantee real emission reductions. If partial CCS for EOR cannot achieve real and enforceable emission reductions, EPA's BSER determinations may fail the requirements of the CAA for setting an NSPS.

What Happened to the "Transitional Sources"

EPA's 2012 GHG NSPS proposal created a category of "transitional sources" exempted from the requirements of the proposed rule.[161] Transitional sources were "coal-fired power plants that, by the date of this proposal, have received approval for their PSD preconstruction permits that meet CAA PSD requirements . . . and that commence construction" within one year.[162] EPA regulations define "commenced construction" to mean "undertaking a continuous program of construction or entering into a binding contract to do so."[163] Thus, EPA's proposed standards did not apply to coal-fired power plants with a PSD permit that commenced construction within one year of the proposal date.[164] EPA was aware of 15 proposed EGUs that would have qualified as transitional sources,[165] six of which planned to use CCS or had received federal funding to

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156 79 Fed. Reg. at 1484.

157 Indiana Dep't of Envtl. Mgmt., Draft PSD/New Source Construction and part 70 Operating Permit Indiana Gasification, LLC, Appendix B BACT Analysis at 1 (2011), *available at* http://permits.air.idem.in.gov/30474d.pdf.

158 *See* Indiana Dep't of Envtl. Mgmt., Addendum to Technical Support Document (ATSD) for a PSD/New Source Construction and Part 70 Operating Permit, Permit No: T 147-30464-00060 at 17, 20 (2012).

159 *Id.*

160 *Id.* at 21 (citing *In re: Mississippi Lime Co.*, PSD App. No. 11-01, 2011 WL 3557194 at Section VI.A (Envtl. App. Bd. Aug. 9, 2011) (emphasis added)).

161 77 Fed. Reg. 22,392 (Apr. 13, 2012) (publishing rule signed by administrator Jackson on Mar. 27, 2012).

162 *Id*. at 22,421.

163 *Id*. at 22,400 (citing 40 C.F.R. § 60.2).

164 *Id*. at 22,395.

165 *Id*. at 22,400.

demonstrate CCS.[166] The 2012 proposal noted that "[r]ecent industry practice" indicated "no more than a few of these . . . will in fact be constructed."[167]

EPA explained that transitional sources should be treated differently because they have "incurred substantial sunk costs and developed plans to commence construction in the very near future;" therefore, applying the proposed standards to them "would likely result in the loss of their sunk costs and . . . cause multi-year delays, or even abandonment" of the projects.[168] These severe consequences might not be "within the scope of [best system of emission reduction]" because they would be "so costly and disruptive."[169] A separate emissions limit for transitional sources might be appropriate, EPA speculated, but it declined to impose one because it lacked sufficient information about these projects.[170] The Agency invited comments regarding the transitional sources' carbon mitigation efforts and any practical problems a new standard might cause. EPA believed that the differential treatment of transitional sources was not inequitable because transitional sources' emissions would still be limited by the terms of their permits and any State regulations.[171] Thus, transitional sources were exempted from the proposed performance standards because they would suffer severe economic harm, EPA lacked sufficient information to impose a different standard, and, because of the small number of transitional sources, holding them to the new standards would yield relatively little environmental benefit.

The rule proposed by EPA on January 8, 2014 removes the "transitional source" designation.[172] EPA wrote that "any former 'potential transitional source' that commences construction *after* publication of this proposal . . . will be subject to the final CO_2 standards established in this rulemaking;"[173] and those that commenced construction *prior to* the proposal's publication would be an "existing source" not subject to the proposed CO_2 standards.[174] Thus, the proposed rule rejected the 2012 proposal's "transitional source" approach; instead, EGUs would be considered an "existing source" or a "new source" based on when construction began.

However, EPA's proposal did discuss several of the projects previously identified as "transitional sources:" the Wolverine project in Rogers City, Michigan, and two other projects in Washington County, Georgia and Holcomb, Kansas. EPA explicitly stated that "[t]his proposal does not apply to the proposed Wolverine EGU project in Rogers City, Michigan."[175] It explained that the Wolverine project "appears to be the only fossil fuel-fired boiler . . . presently under development that may be capable of 'commencing construction'" in the next year.[176] EPA noted that it "has not formulated a view as to the project's status in the development process or as to whether the proposed 1,100 lbs CO_2/MWh standard or some other CO_2 standard of performance would be representative of BSER for [Wolverine]," and invites comments on this issue.[177] The proposed rule also notes that the Washington and Holcomb projects, which are fossil-fuel EGUs without CCS, are likely to be considered existing sources because the project's developers have represented to EPA that they have commenced construction. However, the proposed rule states that neither of these facilities sought a NSPS applicability determination from EPA and if they have not actually commenced construction, the projects "will be addressed in the same manner as the Wolverine project."[178]

EPA carefully limited its discussion of any alternate standard to the facts at hand. It wrote that the treatment of the Wolverine, Washington County, and Holcomb projects was "severable from its treatment of differently situated sources."[179] EPA asserted that this severability was "logical because of the record-based differences between these sources and differently situated sources," and because "there is no interdependency in EPA's treatment of the different types of sources."[180] Finally, it stressed that these projects were the only fossil fuel-fired EGUs "that appear to remain under development."[181] This language recalled the 2012 proposal's observation that only a small number of the "transitional sources" would eventually be built.

In sum, EPA has discontinued its "transitional sources" designation. The Agency might permit an "alternate CO_2 standard" for certain enumerated projects, but has not made a final decision about whether an alternate standard would be appropriate. EPA reasoned that an alternate standard would be appropriate because of the significant economic losses those projects would suffer. It appears unlikely that EPA would entertain an alternative standard for any other power plants.

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166 *Id*.
167 *Id*. at 22,421.
168 *Id*. at 22,422.
169 *Id*. at 22,422, 22,423.
170 *Id*. at 22,423.
171 *Id*.
172 79 Fed. Reg. at 1462 n.128.
173 *Id*. (emphasis added).
174 *Id.*
175 *Id*. at 1461.
176 *Id*.
177 *Id.*
178 *Id.*
179 *Id.* at 1462 n.129.
180 *Id*.
181 *Id*. at 1461.

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